From: Paul Tranquill <Paul.Tranquill@parsons.com>
To: <bmoore@ladwp.com>, <tconki@dwp.ci.la.ca.us>, <rand-c@ipsc.com>
Date: Thursday, February 15, 2001 11:23:51 AM
Subject: Low NOx Burners

The attached report details the latest commercial installation of the new 3 stage Low NOx Burners with overfire air. The reported NOx emission rate is <0.17 lbs/MMBtu. The burners are B&W DRB-4Z. These have been installed on a wall fired Powder River Basin coal fired unit.

From: Krishna Nand <Krishna.Nand@parsons.com>
To: Krishna Nand <Krishna.Nand@parsons.com>, Rand Crafts <Rand-C@ipsc.com>
Date: Sunday, February 11, 2001 9:42:36 PM
Subject: Re: Overview Table for HP_DensePak Project

Rand,

B. NOx Control Evaluations
1. Depending on the type of burner and boiler, SCR is the presumptive BACT.

As you are aware, there are many "flavors" of SCR depending on the type of catalyst and reducing agent used. We will most likely consider a few likely variations.

2. In addition to SCR, we will evaluate ammonia SNCR.

First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner

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Presented to:
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Orlando, Florida, U.S.A.

BR-1710

Abstract

Reliant Energy's W. A. Parish Generating Plant has taken a proactive approach to address ongoing state and federal guidelines regarding NOx emission reductions. In May 2000, the first commercial DRB-4Z™ low NOx burners with an interlaced overfire air system were placed into operation on Unit 6. Long-term pre-retrofit NOx emissions were 0.40 lb/Mbtu. Performance tests conducted in the fall and winter of 1999 indicated pre-retrofit NOx levels of 0.35 lb/Mbtu. Post-retrofit NOx emissions are 0.17 lb/Mbtu or lower at full load. Actual NOx emission performance exceeded the guarantee level at full load. Achieving such low NOx emission levels on an opposed wall-fired boiler retrofit project, when firing Powder River Basin (PRB) coal, is a significant technical and operational milestone.

Plant and Unit Background

The W. A. Parish facility is located in Thompsons, Texas, 25 miles southwest of downtown Houston. The plant is located on 4,880 acres and nearly encompasses Smithers Lake, which supplies cooling and circulating water to the plant. There are a total of eight generating units at this site. Units 1 through 4 are gas-fired and generate 1,215 MW of electricity. Units 5 through 8 are coal-fired and generate 2,560 MW of electrical power. Unit 6 is a 690 MW natural circulating, opposed-wall coal-fired boiler originally supplied by B&W and placed into service in 1978. The unit generates a main steam flow of 4,745,000 lbs/hour at 2,620 psig at 1005/1005° F. Seven B&W-89 pulverizers supply coal to 56 DRB-4Z™ low NOx burners (see Figure 1). Thirty two burners are located on the furnace front wall in 4 rows and 24 burners are located on the furnace rear wall in 3 rows (see Figure 2). Forty of the 56 burners are dual fuel designed to fire natural gas when required. A total of 12 dual zone overfire air NOx ports are located on the front and rear furnace walls just above the top row of burners.

Project Goal

The goal for this burner retrofit was to achieve a 40% reduction in NOx emissions from the most recent baseline levels of 0.35 lb/Mbtu.

Scope of Supply

Unit 6 was originally supplied with 56 B&W dual register burners (DRBs) as shown in Figure 3. These original burners were supplied to comply with applicable federal New Source Performance Standard (NSPS) requirements. Under NSPS regulations in 1978, the maximum allowable NOx emission limit was 0.7 lb/MBtu. Long-term typical NOx emissions from this original equipment were approximately 0.4 lb/MBtu when firing PRB coal. No overfire air system was included in the original boiler design.

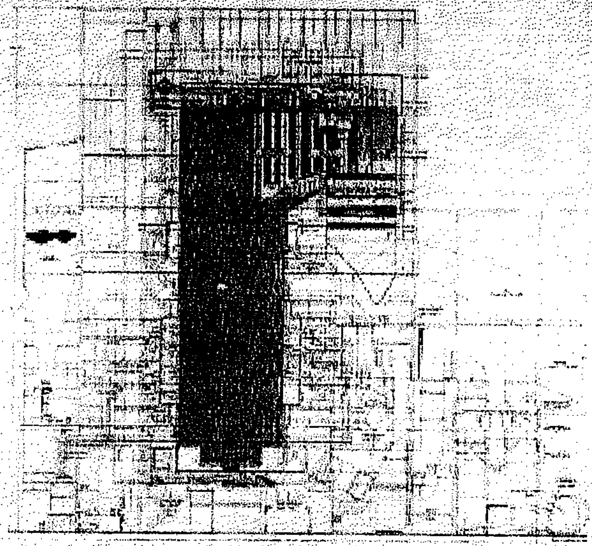

Figure 1 Unit 6 generates 690 MW firing Powder River Basin coal. This unit was placed into service in 1978.

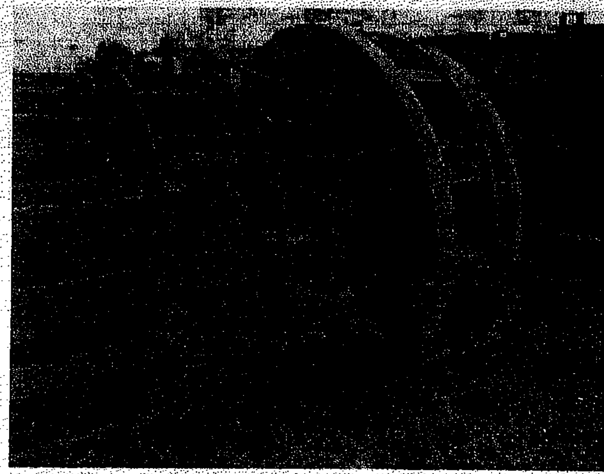

Figure 3 The low NOx Dual Register Burner (DRB) was supplied with the original boiler contract. Several proven design features of this burner were incorporated into the current generation low NOx burners installed on Unit 6.

To meet the goals of this NOx retrofit project, 56 advanced DRB-4Z low NOx burners were supplied (see Figure 4).

The DRB-4Z burner features a patented triple air zone design. The three air zones are defined as shown in Figure 5.

Low NOx burners of the 1990s were developed using single and dual air zones. The DRB-4Z has advanced this design concept with the addition of a third air zone. This third air zone, the transition zone, is located adjacent to the coal nozzle. The transition zone acts as a buffer between the fuel rich flame core and the inner and outer secondary air streams. The flow field produced by the transition zone draws gases from the outer portions of the flame inward toward the flame core. NOx formed in the oxygen-rich outer flame region is reduced to nitrogen in the process (see Figure 6).

This new design results in significantly lower NOx emissions than what is achievable with traditional single or dual zone low NOx burners.

The DRB-4Z burner was conceptually developed using proprietary Computational Fluid Dynamic (CFD) modeling. Modeling confirmed the advantages of an additional air zone surrounding the burner nozzle. This additional air zone helped accomplish critical aspects of mixing around the flame core. A prototype burner was constructed and refined through an extensive program of large-scale combustion tests performed in B&W's 100 million Btu/hour Clean Environment Development Facility (CEDF) located in Alliance, Ohio.

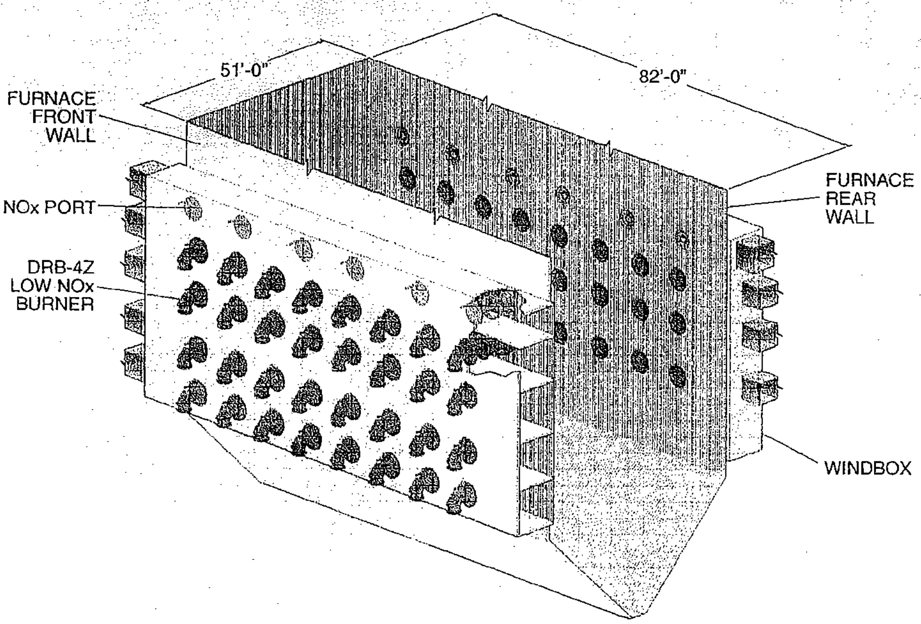

Figure 2 Fifty-six dual fuel low NOx burners are arranged in an opposed firing pattern. Twelve OFA air ports are located above the top row of burners as shown.

The mechanical design of the DRB-4Z burner draws heavily on past B&W low NOx burner designs, which have demonstrated excellent mechanical reliability in the severe conditions prevalent in utility boiler service (see Figure 7).

All B&W low NOx burners are constructed with heavy, high quality, stainless steel plate for portions of the burner exposed to high temperatures. This is combined with a system of stiffeners to maintain the structural integrity while accommodating thermal expansion (see Figure 8).

Adjustable spin vanes provide online tuning capability. Each burner has individual air flow control capability by a manually adjustable slide damper. Relative airflow

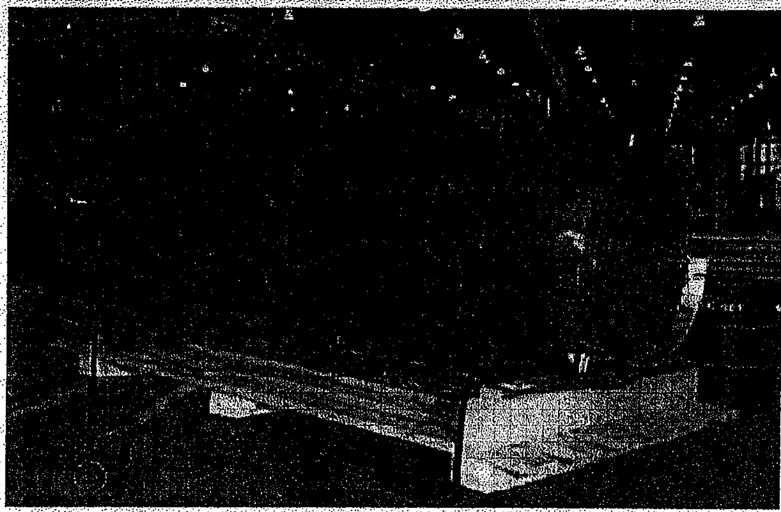

Figure 4 The DRB-4Z™ burner is completely shop assembled as one shipping unit.

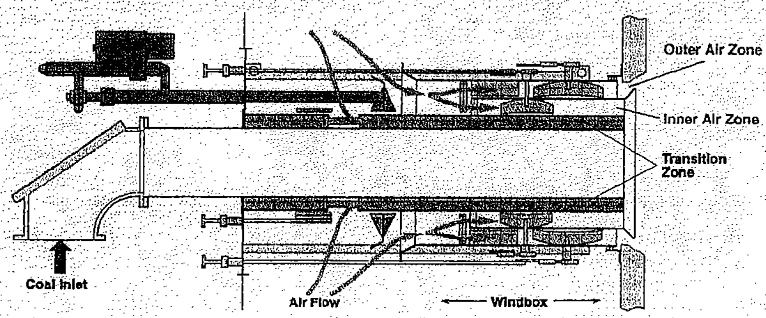

Figure 5 Sectional sideview of DRB-4Z™ burner. In this patented burner design, three distinct air zones are provided.

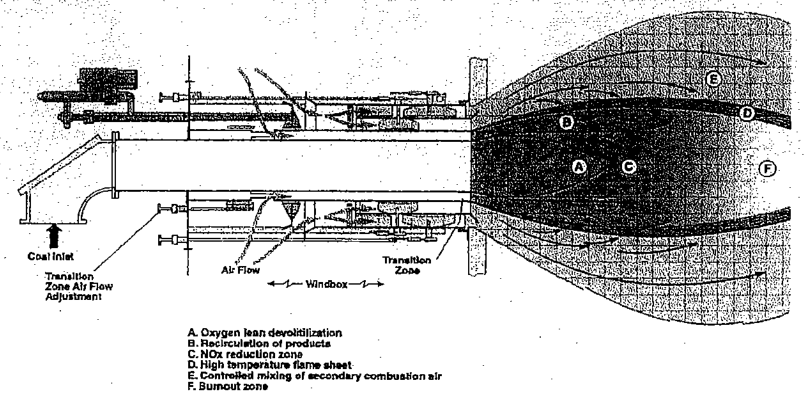

Figure 6 The transition zone acts as a buffer between the outer air zones and the fuel rich flame core. This new design significantly lowers NOx emissions from what is achievable with traditional single or dual zone low NOx burners.

measurement to each burner is provided by a multi-point pitot grid. The burner is shop assembled as a single shipping unit ready to install using provided hardware. New resized burner furnace tube openings are supplied for each burner as well as necessary material to interface the new burner to the windbox casing and support system.

Twelve dual air zone overfire air (OFA) NOx ports are installed above the upper level of low NOx burners. (See Figure 9). Six OFA ports are located on the furnace front wall and six are located on the rear wall. New OFA furnace wall openings were installed. The OfA ports are arranged in an interlaced pattern based on results obtained from a number of CFD analyses. CFD modeling was used during the design phase to optimize the location, diameter, airflow, and side-to-side spacing of the dual air zone OFA ports. The final locations were selected to accomodate existing structural 'interferences' such as buckstays, steel, and walkways to keep installation costs reasonable. A typical manually operated OFA port is shown in Figure 8.

A manually operated dual air zone NOx port is depicted in Figure 9. The port is equipped with a sleeve damper to adjust total air flow to a given port. A pitot grid is provided to locally indicate air flow to each port. A manually adjustable core air damper directly controls flow to the core (inner) zone of the NOx port. The core air damper admits a specific amount of combustion air to provide sufficient jet stream penetration into the furnace. The balance of the air to the NOx port is introduced with swirl to improve near field mixing. The swirl is set by manually adjustable vanes in the outer zone. The overall design optimizes the mixing of air and flue gas in the upper furnace. Well-designed and controlled mixing promotes burnout of the fuel and completes the staged combustion process to control carbon monoxide (CO) emissions. Each port is constructed of a heavy-duty alloy steel plate forming the furnace end of the port (see Figure 10).

The OFA port wall openings, ductwork, dampers, air foils, and expansion joints are also part of the project. The complete burner and OFA port system is optimized using proprietary B&W CFD models.

Performance

Unit 6 primarily burns a PRB sub-bituminous coal. A typical coal analysis is shown in Table 1.

The unit was returned to service in May 2000. The combustion system was tuned during the summer peak load season. Final NOx performance results firing PRB coal are shown in Figure 11. At full load, NOx was reduced to 0.17 lb/Mbtu or below, which represents a 51% reduction from pre-retrofit levels. CO emissions are approximately 100 ppm at full load with one mill out of service. CO emissions are typically less than 50 ppm with all mills in service. Unburned carbon, on an LOI (Loss on Ignition) basis, is typically about 0.3%. LOI was basically unchanged from pre-retrofit levels. The unit has operated near full load since initial tuning and testing was completed. The NOx, CO, and LOI levels continue to run within the ranges with various pulverizer/

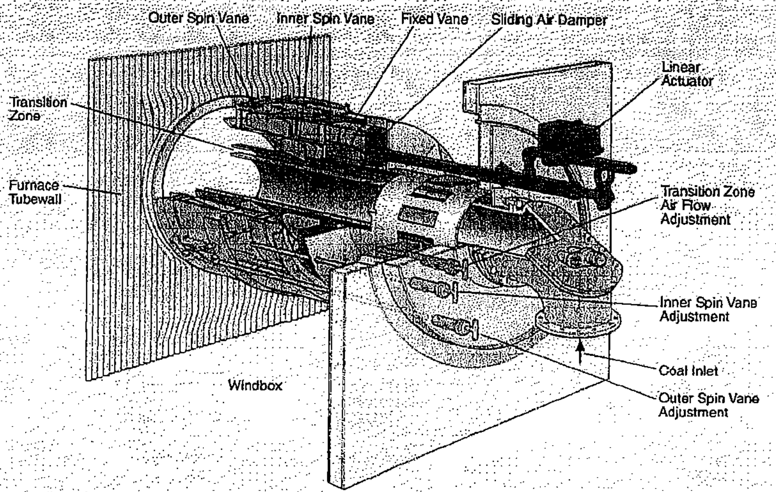

Figure 7 The DRB-4Z™ burner is constructed with simple, heavy-duty mechanical components.

Figure 8 The furnace end of the low NOx burners is constructed of heavy-duty stainless steel plate to maintain structural integrity of the burner while accommodating thermal expansion.

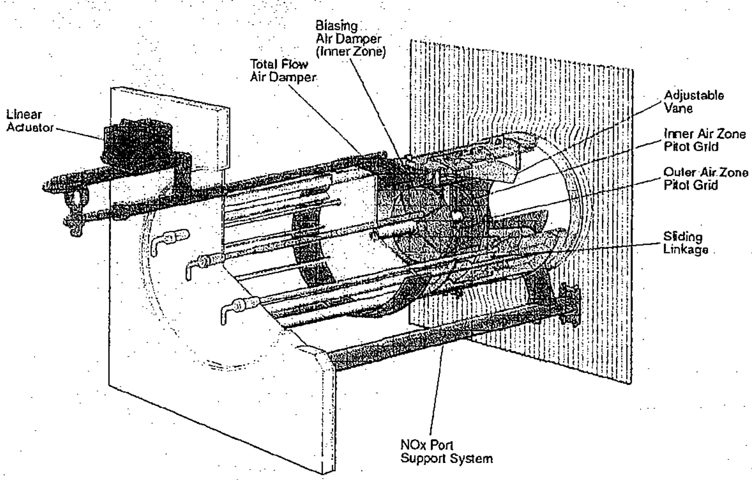

Figure 9 Dual zone OFA port equipped with a total airflow damper and a core air damper.

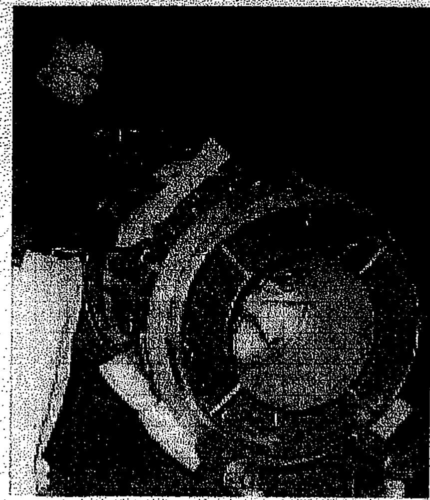

Figure 10 The OFA port is constructed of heavy-duty steel plate. Each is equipped with a pitot tube grid to measure individual airflow to each port.

Table 1
Ultimate and Proximate Coal Analysis

Ultimate Analysis (% by weight)	
Carbon	48.73
Hydrogen	3.51
Oxygen	12.41
Sulfur	0.46
Nitrogen	0.69
Moisture	28.67
Ash	5.53
Total	100.00
Proximate Analysis (as received %)	
Moisture	28.67
Volatile Matter	32.05
Fixed Carbon	33.75
Ash	5.53
Total	100.00
Higher Heating Value	8,650 Btu/lb

burner groups in service, normally operating with six of seven pulverizers.

As mentioned previously, 40 of the DRB-4Z burners have the capability to fire natural gas in addition to coal. Several brief tests were performed firing natural gas. It was found that firing natural gas at full load produced a significant burner rumble. This problem will be addressed by modifications to the burner air vane and/or gas nozzles during a future planned outage.

B&W Construction Company provided installation services. Innovative construction techniques, such as moving the low NOx burners into final position via a rail and dolly system, helped overcome construction access problems. All work was completed safely and the unit was returned to service on schedule. The

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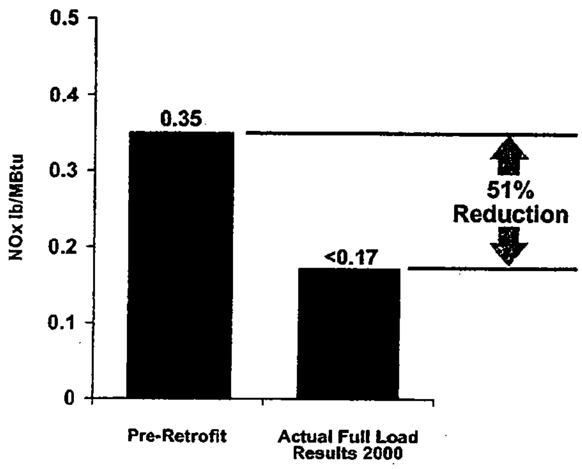


Figure 11 Unit 6 NOx results—post retrofit at full load.

complete shop assembly of the burners and OFA ports reduced the installation time and costs.

Summary

The primary objective of this retrofit project was to reduce NOx by 40% from baseline levels. The low NOx combustion system retrofit has not impaired unit operational flexibility and control. The project objective of reducing NOx emissions by more than 40% was accomplished. The DRB-4Z burner and advanced OFA system can consistently achieve NOx emissions of 0.17 lb/Mbtu or lower at full load with even lower NOx as load is reduced. (See Figure 12) Mechanical reliability of the DRB-4Z burners and OFA ports has been good and it is expected that long-term maintenance costs will be low. Close cooperation between Reliant Energy and B&W throughout the project contributed positively to the success of this project.

Acknowledgements

The authors would like to acknowledge and recognize the following organizations that helped make this project a success: Reliant Energy, W.A. Parish plant operators, technicians, engineering staff, environmental, maintenance services and contractor services; B&W Field Engineering Services; McDermott Technology, Inc., Alliance, Ohio; Amber, Inc. (electrical contractor); Safway Steel Products (scaffolding); Protherm (insulators); Zachary Construction Co. (general labor); B&W Construction Company (low NOx retrofit contractor), and B&W Service Company employees.

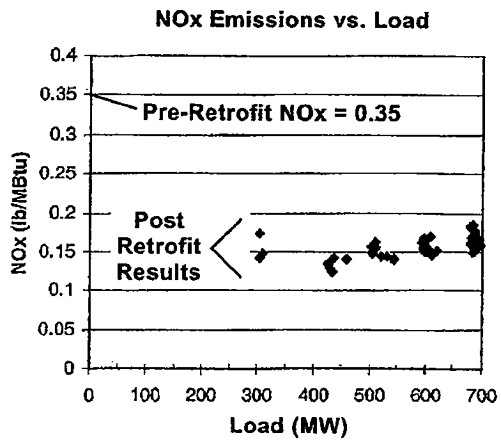
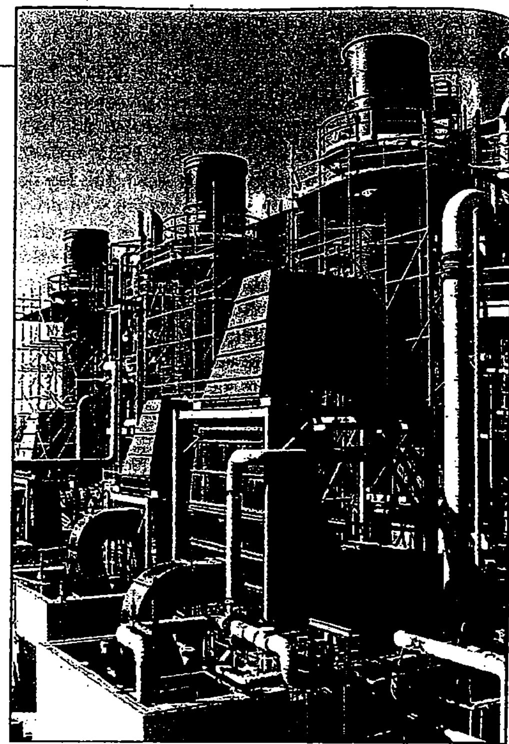


Figure 12 NOx emissions vs. load. Performance data recorded during July 2000.

Cost-effective NOx Reduction

In evaluating options, don't forget to take a look at hybrid technologies



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Nitrogen oxides (NOx) are among the primary air pollutants emitted from combustion processes. NOx emissions have been identified as contributing to the degradation of visibility and the formation of ground level ozone and of acid rain, and they have raised human health concerns. As a result, environmental regulations (box, p. 81) have constituted the main driver forcing industrial firms to install systems that control NOx emissions.

In light of the numerous stringent (but flexible) regulations being proposed or adopted, and the competitiveness of the business environment, engineers responsible for complying with the regulations may not have the resources to select the optimum control strategy. Here, we offer guidance on how to evaluate applicable NOx-control technologies and select a suitable, cost-effective control method or methods. Although, the emphasis of this article is on emissions from boilers and fired heaters burning gas or low-sulfur oil, the evaluation strategy and the cost information may be applicable for other fuels, as well.

NOx-formation mechanisms

There are two primary "kinds" of NOx generated during combustion: fuel NOx and thermal NOx.

NOx that is formed due to conversion of chemically bound nitrogen is referred to as fuel NOx. Depending on the nitrogen content in the fuel, about 30 to 60% of the fuel-bound nitrogen is converted to NOx during combustion.

Thermal NOx refers to nitrogen oxides formed from high-temperature oxidation (or "fixation") of atmospheric nitrogen. This kind of NOx formation is a strong function of temperature. Figure 1 shows the equilibrium concentration of nitrogen oxide as a function of temperature. Although equilibrium may not necessarily be achieved during combustion, the curve indicates the importance of temperature on NOx formation.

Thermal NOx formation can be modeled by this equation [1, 2]:

$$[NO] = k_1 \exp(-k_2/T)[N_2]\ [O_2]^{1/2}\ t$$

where the bracketed terms pertain to concentrations, the k terms are constants, T is absolute temperature and t is residence time.

Inasmuch as NO is by far the major component of NOx, this equation suggests that thermal NOx formation is an exponential function of temperature, and a square-root function of oxygen concentration. So, by manipulating the temperature or the oxygen concentration, or both, the formation of thermal NOx can be controlled.

In a given plant installation, the relative potentials for generating fuel NOx and thermal NOx vary according to the particular circumstances, such as the type of fuel used and the combustion temperature. As will be seen in this article, some NOx-control techniques deal only with thermal NOx, and some with both kinds.

NOx-control technologies

Depending on the source of NOx, the main control strategies for reducing NOx emissions can be characterized into two types: modification of the combustion process, to control the mixing of fuel and air and thereby reduce flame temperature or oxygen concentration in the flame zone, lessening thermal NOx formation; and post-combustion control of fluegas to remove the NOx, whether fuel-derived or thermal in origin. Several reviews available in the literature describe the details of the specific control technologies based on these two options [3, 4].

Each method is proven, and effective for its own set of circumstances. However, the real challenge is not merely to reduce NOx, but also to maintain the performance and safety of the boiler or fired-heater system while minimizing changes to operations and maintenance.

Post-combustion techniques: Emissions of NOx have been successfully controlled, post-combustion, by selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) technologies*. These are the only technologies discussed in this article that cope with fuel NOx; they

*For more on SCR, see pp. 95ff.

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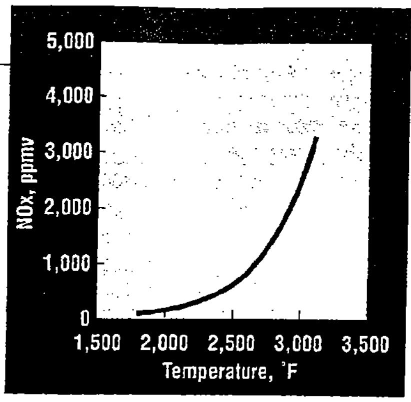

FIGURE 1. The functional relationship between NO concentration and temperature is a key consideration in the functioning of NOx-abatement strategies

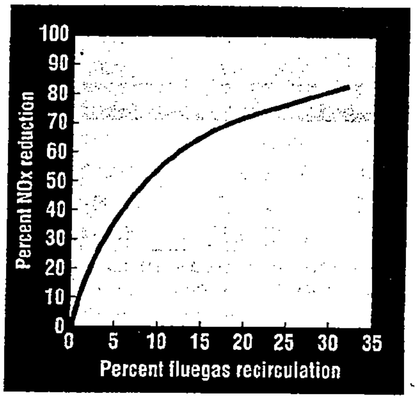

FIGURE 2. The greater the fluegas recirculation, the greater the percent reduction in NOx formation

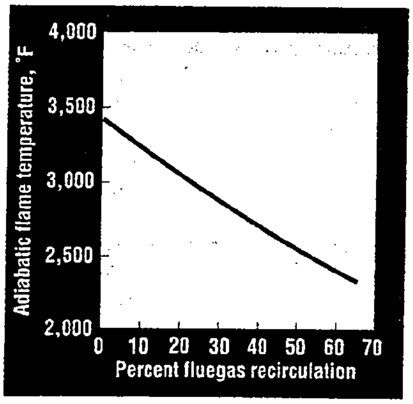

FIGURE 3. Any increase in the amount of fluegas recirculation lowers the formation of NOx, because it causes the adiabatic flame temperature to fall off

TABLE 1. EFFICIENCY AND RELATIVE COST OF SELECTED NOx REDUCTION TECHNOLOGIES

	NOx-reduction Efficiency, %	Cost Relative to That of LNB
Combustion control:		
Low excess air (LEA)	0 - 15	<0.1
Off-stoichiometric combustion (OS)	30 - 50	0.2
Low-NOx burners (LNB)	30 - 50	1
Water-steam injection (WSI)	40 - 60	0.2
Induced fluegas recirculation (IFGR)	50 - 75	0.2
Wind-box fluegas recirculation (WFGR)	50 - 80	1
Post-combustion control:		
Selective noncatalytic reduction (SNCR)	25 - 50	2
Selective catalytic reduction (SCR)	70 - 90	3.5

also accommodate thermal NOx.

In SNCR, ammonia or another nitrogen-based compound, such as urea, is injected downstream of the combustion zone to chemically reduce NOx. SCR systems also reduce NOx from fluegas by reaction with ammonia, but in the presence of a catalyst. These two technologies, especially SCR, can reduce NOx emissions by up to 90%.

However, the technology for SCR and SNCR tends to be more complex than that for other NOx-control methods. So, they are costly. For example, application of SCR can cost about three to 15 times more than some combustion-control methods.

Combustion control: For systems generating thermal NOx (for example, in the case of fuel-gas firing), it is more cost-effective to reduce NOx emissions using combustion control. This approach alters the characteristics of the combustion process to minimize NOx formation in the first place and, thus, can also be categorized as pollution-prevention technologies.

As implied earlier, formation of thermal NOx can be reduced by either changing the combustion stoichiometry (staged combustion) or introducing inerts to lower the peak flame temperature in the flame zone.

Stoichiometry-based methods: Stoichiometry-based combustion controls employ such devices and processes as: low-NOx burners (LNBs), over-fire air (whereby ports for feeding excess air are installed above the array of burners), and burners out of service (whereby a portion of the burners in an array are used not for combustion but for feeding air). Each of these technologies effectively controls NOx emissions by providing air staging to create an initial, fuel-rich zone (partial combustion zone) followed by an air-rich zone to complete the combustion process.

Some burner manufacturers also offer fuel staging, which results in extremely low levels of NOx, below 50 ppm. This approach likewise changes the stoichiometry of the combustion.

Since the cost of an LNB is comparable to that of a traditional burner, LNBs are used by choice in new combustion units. But for retrofit applications, the choice is not that straightforward.

Use of inerts: Water-steam-injection (WSI) and flue-gas recirculation (FGR) methods reduce thermal NOx formation by introducing inerts, which absorb heat, thereby reducing peak flame temperatures.

For instance, water injection reduces flame temperatures because the latent heat of vaporization of the water absorbs some heat. However, apart from lowering NOx, it decreases the combustion efficiency by about 1 to 4%. Thus, it is mainly recommended as a temporary control measure for reducing NOx emissions during peaking periods.

FGR technology does not suffer from this handicap, and has minimal impact on efficiency. In a typical FGR application, about 10 to 25% of the fluegases is recycled back to the combustion zone, reducing the flame temperature and thereby lowering NOx emissions by 50 to 80%.

The effectiveness of FGR in reducing NOx formation depends on the amount of fluegas recirculated (Figure 2). Although reduction efficiencies as high as 90% have been observed, the high recirculation rates associated with these high reductions may affect flame stability.

The effect of fluegas recirculation rate on the adiabatic flame temperature is shown in Figure 3. This figure shows that even a 10% recirculation rate causes the adiabatic temperature to drop considerably, resulting in a rapid decrease in NOx formation.

FGR does not substantially affect the overall efficiency of the combustion process. However, the division between the radiant-heat duty and the convection-heat duty changes: FGR lessens the heat transfer in the radiant section and, correspondingly, increases the heat recovery in the convection section.

Thus, FGR technology works on a principle different from that of stoichiometry-based combustion controls. In practice, it can effectively be used in series with LNB or other stoichiom-

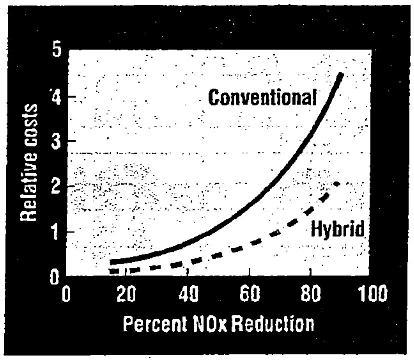

FIGURE 4. Hybrid technologies, relying on both combustion control and post-combustion treatment, show attractively low capital costs

TABLE 2: TYPICAL COSTS OF SELECTED NOX REDUCTION TECHNOLOGIES FOR GAS AND OIL FIRED COMBUSTION UNITS. (INCLUDES FIRED HEATERS AND BOILERS)

	Combustion-unit size			
	40 million Btu/hr	100 million Btu/hr	780 million Btu/hr[b] (75 MW)	3,400 million Btu/hr[b] (320 MW)
Capital cost, $:				
IFGR	66,000	104,000	238,000	424,000
LNB	124,000	269,000	921,000	2,045,000
SCR	a	689,000	2,250,000	6,400,000
IFGR + SCR	a	587,000	1,812,000	4,904,000
Total annual cost (TAC), $:				
IFGR	12,400	19,200	52,300	93,300
LNB	26,100	56,500	193,900	430,600
SCR	a	191,400	625,000	1,778,000
IFGR + SCR	a	117,300	362,500	980,800
Typical Cost Effectiveness, $/ton NOx reduced:				
IFGR	1,500-7,000	1,200-4,500	800-1,600	250-700
LNB	4,500-15,000	4,000-12,000	2,600-3,500	800-2,600
SCR	a	10,000-27,000	3,600-10,000	1,000-8,000
IFGR + SCR	a	6,000-15,000	2,000-5,500	550-4,000

a = Not cost effective. Compliance can be achieved by other cost-effective alternatives.
b = Combustion modifications alone may not be sufficient to meet compliance.

Note: Cost estimates are highly variable, and accurate estimates can only be made on a case-by-case basis.

etry-based control technologies, to control NOx emissions in excess of 75% and improve combustion performance alike.

Most of the cost associated with traditional FGR technology (also referred to as windbox FGR) is due to an additional hot-gas-fan requirement to transport the fluegas. However, the authors' company has been grooming a technology that eliminates the need for a separate FGR fan and windbox mixing devices. This technology, known as induced FGR (IFGR), uses excess capacity of the combustion unit's forced-draft fan to draw (induce) fluegas into the combustion air at the fan inlet.

The IFGR approach requires only minor modifications, and has relatively little or no impact on performance and operation, lowering NOx emissions by 50 to 80% while typically improving the combustion efficiency and performance. This technology has been applied on more than 20 combustion systems, ranging in size from 40 through 6,000 million Btu/h. Cost information generated during the execution of these projects has been used to develop the economic analyses discussed in the following section.

NOx-control efficiencies of several of the control technologies mentioned above, and their relative costs, are summarized in Table 1. The relative cost information is based on the U.S. Environmental Protection Agency's (EPA's) Alternative Control Techniques (ACT) guidelines [4] and vendor information, and is discussed in detail in the next section of this article.

Assessing cost-effectiveness

To estimate the cost impact of stringent standards requiring NOx reductions above 75% (such as the new Texas Natural Resources Conservation Commission [TNRCC] regulations; box, p. 81), we have made a cost-effectiveness analysis comparing use of four NOx-reduction strategies: low-NOx burners, induced fluegas recirculation, selective catalytic reduction, and a combination of the last two.

The analysis is in accordance with EPA's ACT documents, TNRCC information [5] and, in some cases, cost estimates based on vendor information. It assumes the use of gas or low-sulfur oil as fuel, and focuses on boilers and fired heaters in four size ranges: 40, 100, 780 and 3,400 million Btu/h. The major results appear in Table 2.

The capital-cost figures for NOx controls include both direct and indirect components. Direct costs are the cost of equipment. Indirect costs include those for project engineering and development. The total annual cost (TAC) includes annual operating and maintenance costs, as well as uniform annual capital-recovery costs consistent with EPA's ACT stipulations.

To compare the cost effectiveness of the four options, the TAC of each is divided by the amount of NOx removed via this option over a one-year period. The results appear in the bottom rows in the table.

It can be seen that there is wide variation among these figures. This diversity arises mainly because of variation in the types of boilers and fired heaters studied, as well as in the operating conditions of those units and in the gas or oil fed to them. Accordingly, the cost estimates in the table are for comparison purposes only. For more precision, estimates should be made only on a case-by-case basis

Our results show that in most cases, smaller units (typified in Table 2 in the 40-million-Btu/h column) can be brought into compliance cost-effectively by combustion control. The analyses also show that the capital costs for LNB technology is about two to three times more expensive than IFGR, or WSI combustion technologies. (However, WSI technology incurs high operating costs resulting mainly from increased energy usage, and thus is not included in Table 2.)

For larger units, including those in which TNRCC proposes to require NOx reductions in excess of 90%, our analysis shows that a hybrid system consisting of combustion controls as well as post-combustion fluegas cleanup is the most cost-effective.

NOx AND THE LAW IN THE U.S.

The U.S. Clean Air Act Amendments (CAAA) of 1990, and, in particular, the Title I (Ozone Attainment), Title IV (Acid Rain) and New Source Review requirements have resulted in various State Implementation Plans (SIPs) aimed at reducing NOx. Up until early December 2000, California's standards were the most stringent, requiring up to 75% reduction in NOx emission. On December 6, however, the Texas Natural Resource Conservation Commission (TNRCC) adopted new NOx-reduction rules that can easily be considered the toughest in the nation [*5*].

For small units, up to 40 million Btu/h, TNRCC has set a limit of 0.036 lb NOx/million Btu. For larger units, the limits go as low as 0.01 lb NOx/million Btu. These new rules are expected to reduce area NOx emissions by 75%. For "major" new industrial sources, of a size that would (in the absence of NOx controls) be anticipated to emit more than 10 tons of NOx per year, the rules require 90% (93% for utilities) reduction from the projected no-controls emission level. And for "grandfathered" major NOx sources (previously exempt from NOx Reasonably Available Control Technology (RACT) rules), the new regulations require them to comply with existing NOx RACT rules. For Texas' Houston-Galveston area (HGA) alone, the cost of retrofitting exiting chemical plants and petroleum refineries to comply with the new regulations has been estimated to be as high as $8 billion.

However, for the HGA, the schedule to reduce emissions has been moved back from originally proposed dates. This change provides an opportunity for early NOx control installers to accumulate emissions credits, as discussed below.

For the industrial sector in HGA, the first 44% of the reductions (90%) is required to be achieved by March 31, 2004, the next 45 % reduction by March 31, 2005, and the final 11% reduction by March 31, 2007. For the utility sector, the first 47% of the reduction (93%) is required by March 31, 2003, the next 48% reductionsby March 31, 2005, and the final 5% reduction two years later.

Meanwhile, as of January 2002, TNRCC will allocate NOx-emission allowances to individual sites, depending on baseline emissions limits set in accordance with 1997-1999 levels. While TNRCC will use emissions specifications for each point source within a plant to calculate the site allowable emission level, a given point source does not have to meet its calculated level — instead, the plant can decide how to spend the allowance. For example, depending on site economics, a plant may opt to "overcontrol" its big emitters and "undercontrol" its smaller ones.

The Texas rules are so flexible that industry can benefit from them. As in California, TNRCC has set rules for emissions banking and trading that offer companies the chance to generate, use, bank or trade Emissions Reduction Credits (ERCs) and Discrete Emissions Reduction Credits (DERC's)*. Any reduction in NOx beyond the allowable limit can be banked as DERC's, having no expiration date. These may be used in the following years to offset new projects or future reductions, or be traded in the market. After January 2002, uniots opting for trade can bank any emission reductions beyond the allowable limit as unused allowances or as ERCs.

New and modified sources will have to buy allowances on the market to offset any increases in emissions. The present NOx price is about $2,000 per ton; by 2005, the figure is projected to rise to as high as $ 44,000. However, recent reports from California indicate that NOx has been traded at as high as $100,000/ton. With these projections, early installation of cost-effective NOx-reduction systems looks to become an obvious option for profiting from the new rules. For more information, see the article, Emissions-trading programs hit their stride, *CE*, June 1998, pp. 32–37.

*ERCs apply to continuous, ongoing NOx-emission operations; DERCs apply to one-time or other discrete emission events.

Analysis by TNRCC [*5*] confirms that such a strategy is the most cost-effective way to meet the new regulations.

In particular, Table 2 shows that a combination of IFGR with post-combustion SCR technology is more cost-effective than SCR technology alone. This is because when SCR is used together with IFGR, the costs associated with catalyst and ammonia-handling systems are significantly reduced, due to lower NOx concentrations.

Table 2 pertains to new-plant and retrofit applications alike. However, retrofit applications entail a number of case-specific factors, such as fuel characteristics, type and size of the combustion unit, the amount of NOx reduction required, and space limitations. Thus, it is harder to generalize about the "true" cost of implementing retrofit NOx-reduction projects than about that in new plants.

Table 2 typifies analysis triggered by specific NOx-reduction levels, mandated by such regulation as that of TNRCC. It is also illuminating to analyze NOx-reduction costs more broadly, as a function of the percent NOx removed. The results from several such control scenarios, for gas fired units, appear in Figure 4.

In that graph, the "relative cost" (along the vertical axis) is the capital cost of control technology relative to the cost of achieving 50% NOx reduction by the use of LNBs. The conventional-technology line on the graph pertains to the use of LNBs for NOx reductions up to 50%, and SCR technology for greater reductions. The dotted line, for "hybrid" technology, refers to the use of IFGR for NOx reductions up to 65%, and to a combination of IFGR with SCR technology for greater reductions.

The conventional-technology curve shows that as the amount of NOx reduction is increased to levels above 50%, there is an exponential increase in the capital cost. It can also be seen that this cost can be reduced by as much as 60% using the hybrid approach presented here.

Similar results for cost effectiveness were obtained. Indeed, the cost effectiveness at higher reduction levels of 90% is about 15 to 20 times that at levels of 65% reduction.

Although the hybrid of IFGR and SCR was shown to be cost effective in our example, this application may not be suitable for all situations. So, other combinations of combustion control with post-combustion control technologies should also be considered, on a case-by-case basis.

Final thoughts

Keep in mind that virtually all of the available NOx-control technologies have the potential to adversely affect the combustion performance or the operation of the unit to which they are applied. Thus, the engineer should assess these potential impacts, hand in hand with the NOx-reduction performance, when selecting the applicable control technology.

The most cost-effective NOx-compliance approach depends on a number of technical, economic and regulatory factors. For smaller units, our analysis indicates that the TNRCC regulations (and similar NOx-reduction strictures that might arise elsewhere) can be met cost-effectively by combustion control technologies.

For systems fired by gas or low-sulfur oil, IFGR technology appears to be most cost-effective approach for improving combustion performance and meeting compliance. For larger units that may require NOx reductions greater than 90%, a combination of combustion control with post-combustion cleanup tech-

IP11_000062

nology appears to be most cost-effective.

For some applications, a hybrid approach of IFGR with SCR promises to be best. Our analyses also indicates that a generalized hybrid concept of combining combustion controls with post-combustion cleanup technologies will prove to be the most cost-effective approach to meeting NOx control above 75% levels.

Finally, keep in mind that one way to minimize the impact of the new TNRCC regulations is to install combustion-control technology early enough to generate emission reduction credits — to cash them in at a later date, trade them at a higher value, or use them to delay major capital expenses such as installation of SCR. With such flexible rules for emissions banking and trading, states such as California and Texas, offer operators a way to gain an advantage from stringent NOx regulations. ■

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IP11_000063

HP DENSE PACK UPRATE PROJECT - ECONOMIC CUT-OFF ANALYSIS

HP Dense Pack	$ 9,400,000
Other Improvements / Debottlenecks	12,000,000
Avoided Costs (nozzle block, etc)	-5,304,000
	$ 16,096,000

Payback Benefit (per year) $ 35,784,704 NPV= -16096000 + 35784704 (P/A, i,N) = $335,423,686

GO/NO GO criteria: Two year payback

Maximum allowable for NOx Control Installation:

35,784,704 X 2yrs - 16,096,000 = $ 55,473,408 (Present worth, not just capital)

CAPITALIZATION OF PROJECT ($MM)				
Technology	Technology Cost	Base Project	Total Cost	Cost Ratio (Total/Base)
LNB	9.9	16.09	25.99	1.62
LNB w/OFA	22	16.09	38.09	2.37
SNCR	18.4	16.09	34.49	2.14
SCR	150	16.09	166.09	10.32

NOx Control Data
Given:

	Capital Costs	O&M Annual Costs:	Economic Life	Cost of Money
LNB	$9.9M	56,222	25 years	9%
LNB w/OFA	22M	1,930,640	25 years	9%
SNCR	18.4M	5,221,118	25 years	9%
SCR	150M	7,033,217	25 years	9%

Net Present Worth Calculations: (Capital outlay + benefit(P/A, i, N) - expense(P/A, i, N) (P/A, 9, 25) = 9.8225796

		NPV Total	NPV Uprate	Difference	Cut-Off	Within Cut-off?
LNB	-($16,096,000+9,900,000) + $35,784,704 (P/A, 9, 25) - $56,222 (P/A, 9, 25) =	$324,971,407	$335,423,686	$10,452,279	55,473,408	Y
LNB w/OFA	-($16,096,000+22,000,000) + $35,784,704 (P/A, 9, 25) - $1,930,640 (P/A, 9, 25) =	$294,458,656	$335,423,686	$40,965,029	55,473,408	Y
SNCR	-($16,096,000+18,400,000) + $35,784,704 (P/A, 9, 25) - $5,221,118 (P/A, 9, 25) =	$265,735,690	$335,423,686	$69,687,996	55,473,408	N
SCR	-($16,096,000+150,000,000) + $35,784,704 (P/A, 9, 25) - $7,033,217 (P/A, 9, 25) =	$116,335,110	$335,423,686	$219,088,576	55,473,408	N

HP DENSE PACK UPRATE PROJECT - ECONOMIC CUT-OFF ANALYSIS

HP Dense Pack	$ 9,400,000
Other Improvements / Debottlenecks	12,000,000
Avoided Costs (nozzle block, etc)	-5,304,000
	$ 16,096,000
Payback Benefit (per year)	$ 35,784,704
GO/NO GO criteria:	Two year payback

NOx Control Data

Given:

	Capital Costs	O&M Annual Costs:
LNB	$9.9M	56,222
LNB w/OFA	22M	1,930,640
SNCR	18.4M	5,221,118
SCR	150M	7,033,217

$$\frac{\text{(Capital Cost - Project) + (O\&M x 2yrs)}}{\textbf{Benefit per year}}$$

			Within Cut_off?
LNB =	$\frac{16,096,000+9,900,000+(56,222x2)}{35,784,704}$	=0.73 year payback	Y
LNB-OFA=	$\frac{16,096,000+22,000,000+(1,930,640x2)}{35,784,704}$	=1.17 year payback	Y
SNCR =	$\frac{16,096,000+18,400,000+(5,221,118x2)}{35,784,704}$	=1.26 year payback	Y
SCR =	$\frac{16,096,000+150,000,000+(7,033,217x2)}{35,784,704}$	=5.03 year payback	N

CAPITALIZATION OF PROJECT ($MM)					
Technology	Technology Cost	Base Project	Total Cost	Cost Ratio (Total/Base)	
LNB	9.9	16.09	25.99	1.62	
LNB w/OFA	22	16.09	38.09	2.37	
SNCR	18.4	16.09	34.49	2.14	
SCR	150	16.09	166.09	10.32	

COST CALCULATION DETAILS (TABLE 3)

Technology	Pre-control NOx Emissions (tons/yr)	Absolute Emission Factor (% reduction)	Absolute Emission Reduction (tons/yr)	Minor Mod Emission Reduction (tons/yr	Capital Costs (MM$)	Unit Fixed O&M ($/yr)	Total Fixed O&M ($/KWh)	Unit Variable O&M ($/MWh)	Total Variable O&M	Life N (yrs)	Interest Rate (%)	CRF	Absolute Annualized Cost	Absolute Cost Effectiveness ($/ton removed)	Incremental Annualized Cost ($/yr)	Incremental Cost for Minor Mod ($/ton removed)
LNB	27,960	15	4,194		9.9	0.035	56,222	0	0	25	9	0.1018	1,064,104	254		
LNB w/OFA	27,960	50	13,980		22	0.048	77,640	0.131	1,853,000	25	9	0.1018	4,170,378	298		
SNCR	27,960	40	11,184		18.4	0.111	178,971	0.356	5,042,147	25	9	0.1018	7,094,353	634		
SCR	27,960	70	19,572		150	1.837	2,967,187	0.287	4,066,030	25	9	0.1018	22,304,155	1,140		
LNB	27,960			2777	9.9	0.035	56,222	0	0	25	9	0.1018			1,064,104	383
LNB w/OFA	27,960			2777	22	0.048	77,640	0.131	1,853,000	25	9	0.1018			4,170,378	1,502
SNCR	27,960			2777	18.4	0.111	178,971	0.089	1,259,119	25	9	0.1018			3,311,325	1,192
SCR	27,960			2777	150	1.837	2,967,187	0.14	1,980,636	25	9	0.1018			20,218,761	7,281

2yr Avg NOx emissions: 25,144 tons
Post-project uncontrolled NOx increase: 2,816 tons
Minor Mod Limit: 25144 + 40 tons (25,184)
Minimum Minor Mod decrease: 2,777 tons
Estimated Costs: Source Vendor Specific, with adjustments based on EPA's CUECost workbook.

			LNB	LNB w/OFA	SNCR	SCR
Fixed O&M	Oprtg Labor		22,489	31,056	98,550	518,882
	Maint Lbr & Cost		33,733	46,584	80,421	546,054
	Re-Capitaliztion Catalyst Bed					1,902,251
Unit O&M			0.03481	0.048074	0.110818	1.8372675
Variable O&M	Urea				5,032,800	
	Ammonia					2,362,500
	Disposal			520,000		38,440
	Power				1983	1,427,528
	Steam					237,562
	Water				7364	
	Lost Revenue			1,333,000		
Unit O&M			0	0.130978	0.356401	0.2874048

Capital Costs adjustments are from direct vendor information.